STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 97-580

January 19, 2000

PUBLIC UTILITIES COMMISSION
Investigation of Central Maine Power Company
Company's Revenue Requirements
and Rate Design (Phase II)

ORDER

WELCH, Chairman; NUGENT and DIAMOND, Commissioners

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I. INTRODUCTION

We are nearing the end of the two-year investigation to set Central Maine Power Company's (CMP) rates to recognize the fundamental restructuring of the electric industry that occurs on March 1, 2000. On that date, customers will be buying their electricity by way of standard offer service or from competitive suppliers. We are in Phase II of the investigation, updating and implementing the decisions we made in our Phase I Order on March 19, 1999.

By our decisions in this Order, we project the costs and revenues of the new CMP transmission and distribution (T&D) utility during its initial year as a power deliverer. We also decide the remaining principles to govern the calculation of CMP costs that are stranded by the elimination of CMP's obligation to provide generation service. After the Commission has authorized CMP to sell its QF power and determined the standard offer prices, the final pieces to calculate the stranded cost revenue requirement will be known. We will then enter into the final update phase, in which the stranded cost revenue requirement for the first two years of retail access will be calculated. We also will design the rates to recover the T&D and stranded cost revenue requirements. We ask CMP for a few specific updates described in the body of this Order in order to undertake these tasks.

II. SUMMARY

In this Phase II Order, we accept CMP's reduction to costs allocated to the T&D function resulting from the elimination of the North Augusta Annex. We also reallocate non-directly assigned A&G costs back to the T&D function because of the elimination of the MainePower business unit, but at a significantly reduced level compared to CMP's proposed reallocation.

As to CMP's request to increase its employee transition benefits recovered from ratepayers due to the elimination of its Technical Services (E-Pro) division, we find that only 21% of the Technical Services operations were related to generation and therefore permit 21% of transition benefits to be recovered in T&D rates. As to employee transition benefits related to employees who transferred to FPL, we find that ratepayers should be responsible for a portion of the Post-Retirement Medical Benefits (PRMB) costs to the extent such costs avoided other employee transition costs which were found otherwise allowable. We conclude that the costs related to the Enhanced Pension Benefit and Permanent Eligibility Enhancement, as well as $300,000 in PRMB costs for those employees who transferred to FPL, should be shared equally between shareholders and ratepayers.

We reject CMP's proposal to increase payroll expenses by $6.6 million to reflect more recent data. We will continue to simply grow the payroll expense through the attrition adjustment, as we decided in Phase I. We use the year 2000 premiums to calculate the rate year medical insurance expense, rather than the trended growth rates proposed by CMP or the general attrition growth rate used in Phase I.

Except for minor issues about the operating costs of the non-divested nuclear assets, there is general agreement about calculation of the costs associated with stranded cost revenue requirement. We describe some expenses that can be deferred before the next stranded cost investigation.

We agree with the IECG that the “no losers” rate design principle adopted in Phase I requires the implementation of T&D versions of Rate SB and Rate O.

III. REVENUE REQUIREMENTS

A. Cost Separations

1. Positions Before the Commission

As part of its Phase II filing, the Company proposed to update its cost separations study for what it believed were four significant events: (1) the Commission’s Phase I Order, which reduced the level of A&G expenses allocated to the T&D company by 4%; (2) the elimination of MainePower as a business unit of CMP; (3) the elimination of the North Augusta Annex from revenue requirements; and (4) the inclusion of costs for energy supply and marketing to reflect the need to settle power supply and trading issues.

OPA witness Jim Dittmer recommends that the Commission reject CMP’s proposed cost separations update. In support of his recommendation, Mr. Dittmer argues that allowing the Company to update one aspect of the study without considering attendant impacts of the event or other changes which might have countervailing benefits would provide a skewed result. Mr. Dittmer also notes that in deciding the cost separations issue in Phase I, the Commission used its informed judgment to set a reasonable level of A&G expenses for the T&D utility. The Commission’s conclusion would not necessarily be altered by a change in corporate structure which results in a change in the allocation factor. Finally, Mr. Dittmer argues that if CMP’s update is to be accepted, other events such as the Company’s proposed merger with Energy East and its increased activity in natural gas distribution also need to be taken into account.

CMP responds that the Commission in its Phase I Order recognized that the A&G allocation might change as a result of updates during Phase II, although any updated amount would need to be reduced by 4% as required by the Commission. The Company also argues that any possible savings from the yet-to-be approved or implemented merger are not properly addressed in this proceeding.

2. Analysis and Conclusion

As we have noted on several occasions, trying to establish A&G costs for an entity that does not yet exist has proven to be a complex and vexing task. In Phase I, we stated that cost separations presented some of the most difficult questions in the case. Nothing in this case or in the recently completed Phase I investigation of Bangor Hydro-Electric Company's T&D revenue requirements has caused us to change our view. *See Public Utilities Commission, Investigation of Stranded Cost Recovery, Transmission and Distribution Utility Revenue Requirements and Rate Design of Bangor Hydro-Electric Company,* Docket No. 97-596, Order (Nov. 24, 1999).

The first step in analyzing CMP's proposed update is to assess the proposal in light of our decision in Phase I. The OPA argues that the Commission, using its "informed judgment" established a reasonable level of A&G costs, which was $1.9 million less than the Company's recommendation. The Company argues that the Commission essentially adopted its methodology but reduced the overall amount allocated to the T&D Company by 4%.

As with many cost separations issues, the result we find most reasonable lies somewhere between the polar positions presented to us. As discussed in our Phase I decision and in our Order Denying Motions in Limine in this phase of the case, we were not fully satisfied with any of the methodologies presented in Phase I. Our decision that none of the cost separation studies either accurately or adequately calculated the level of A&G costs attributable to the T&D company after the generation function was shed counsels against the mechanical application set forth in the Company's Phase II proposed update. This is not to say, however, that no adjustment to the T&D A&G amount established in Phase I is warranted at this point given the Company's elimination of the MainePower business unit.

As we noted in our Order Denying Motions in Limine, the Company's elimination of MainePower represents a significant change in the Company's corporate structure. In its original cost separations study, the Company assigned non-directly assigned A&G costs between the utility and MainePower by applying a variety of allocation factors, including revenues, expenses, plant investment and employee levels. The application of these factors resulted in $3,923,000 of A&G costs being allocated to MainePower. We do not accept the Company's proposition that these costs are entirely unavoidable and by necessity must be absorbed by the T&D company.

As we have noted recently on several occasions, A&G costs are neither entirely fixed nor entirely variable in situations, such as this, where a utility either adds or eliminates a function. *See Docket No. 97-596, supra. at 10 and Docket No. 97-596,* Accounting Order (Sept. 8, 1999). The question then becomes how much of the A&G costs allocated to MainePower should be considered fixed and transferred to the T&D utility. In this instance, based on the extensive information presented in this case, we believe the Commission can to make a more refined determination of what should be allocated to the T&D function.

First, we would eliminate, as the Company has, the direct costs of $1,620,000 attributable to Maine Power. We allocate the indirect A&G costs on a line-by-line basis as follows:

	Proposed by CMP	**Percent Allowed**	**Allowed Recovery**	**Eliminated**
Allocated from OSD Information Services	$1,312,000	85%	$1,115,200	$196,800
Human Resources	637,000	50%	318,500	318,500
Accounting/Legal/Risk/Treasury	656,000	50%	328,000	328,000
Other OSD	713,000	50%	356,500	356,500
Allocated from Holding Company	191,000	50%	95,500	95,500
Plant Related Expense	414,000	25%	103,500	310,500
Total A&G	$3,923,000		$2,317,200	$1,605,800

Our decision to eliminate 75% of the A&G plant expenses is based on our belief that the Company, even in the short-term, can mitigate these costs through rental or lease arrangements. We will, however, allow the Company to retain in rate base the $4,345,000 of A&G plant allocated to MainePower based on our belief that it would be extremely difficult during the short-term, i.e., the rate-effective year, to dispose of such property in a way that ensures maximum cost recovery.

In making these adjustments, we note our agreement with CMP's response to Mr. Dittmer that accounting for savings from the proposed merger with Energy East is not an issue in this case.

As part of its proposed cost separations adjustment, the Company also recommended decreasing expenses by $607,468 and decreasing rate base by $2,691,100 to reflect the fact that CMP will cease operations at the North Augusta Office Annex as a result of the elimination of Technical Services. In our Phase I Order, we found that it was unlikely that CMP could reduce its A&G plant-related expenses during the rate year and therefore assigned no A&G plant to the generation function. We accept the adjustment with the recognition that our original conclusion that A&G plant costs could not be eliminated through the rate year may have been overly pessimistic, resulting in an overallocation of costs to the T&D function.

Finally, the Company has proposed that $481,785 of Energy Trading and Marketing costs be allocated back to the T&D company to recognize the fact that the services of this group will be needed for some time after March 1, 2000 to settle all power supply and energy trading issues that relate to CMP's integrated utility load serving obligations. These costs represent one-third, or four months, of a full year's expenses. No party has specifically challenged this adjustment. Given the current volatility in the energy market, we believe CMP's adjustment to be reasonable and accept it.

B. Employee Transition Benefits

1. Overview

Employee Transition Benefits fall into two broad categories: severance benefits, which are mandatory under the statute, and early retirement benefit enhancements (ERBE), which are discretionary. The ERBE consists of three separate programs: the Enhanced Pension Benefit (EPB); Permanent Eligibility Enhancement (PEE); and Post-Retirement Medical Benefit (PRMB). As part of its surrebuttal filing in Phase I, the Company requested that the following amounts be deducted from the FPL asset sale available value:

ITEM	**SURREBUTTAL AMOUNT**
Enhanced Severance Benefits	$1.0
Early Retirement Benefit Enhancements For both Pension and Post Retirement Medical Benefits	$8.1
Pension and Medical Plan Curtailment Costs Pursuant to SFAS 88 and 106	$5.5
Reserve for NEHI to Fund Unvested Portion of Post-Retirement Benefits of Transferring Employees	$1.0
TOTAL	**$15.6**

According to CMP, its estimate of severance benefits costs included in its Phase I filing was based upon the divestiture of its generation business only. Since the filing of the Phase I case, CMP has closed its MainePower and Technical Services (E-Pro) business units. In its Phase II filing, CMP has included a claim for the severance benefits associated with MainePower and Technical Services. The Company claims that the costs of these severance benefits qualifies for recovery because the closure of the two business units was the direct result of retail competition. CMP proposes to recover the total severance costs over a three-year period. Another component of the employee transition costs is the Early Retirement Pension Benefit (ERPB). In its revenue requirement filing, CMP has included the cost of early retirement benefits paid to Technical Services employees in addition to benefits paid to employees of the generation business unit.

In its Phase II filing, the Company revised its estimates for Severance Benefits to $2.4M; ERBE to $10.6M and Reserve for NEHI to fund Post-Retirement Benefits to $2.1M. The increases in both the Severance Benefit Package and the ERBE package were primarily driven by the Company's elimination of Technical Services and MainePower.

The Company's request for recovery of employee transition costs for its terminated MainePower employees has not been questioned and we find it appropriate under the provisions of 35-A M.R.S.A. § 3216. We will discuss the Company's proposal for recovery of its former (E-Pro) Technical Services employees as well as those employees who transferred to FPL in the sections below.

2. Technical Services (E-Pro)

a. Positions Before the Commission

As part of CMP's recovery of Employee Transition Benefits, the Company is seeking to recover benefits associated with the Technical Services Division. CMP has proposed to recover Enhanced Severance Payments of $856,000 and Early Retirement Pension Benefits of $1,874,000 over a three-year period. The benefits CMP is seeking to recover relate to severance benefits paid to the Technical Services employees. According to CMP's filing, the decision to sell Technical Services was the result of the restructuring of electric utilities.

OPA has proposed a partial recovery of the benefits CMP is seeking to recover. Specifically, OPA recommends an allocation of the transition costs to non-jurisdictional activities since not all of Technical Services work related to Maine public utility jurisdictional activities. In determining the non-jurisdictional portion, OPA applied the ratio of the percent of Technical Services costs billed to third parties during 1998.

In the Bench Analysis, the Advisory Staff took the position that CMP was not entitled to full recovery of the E-Pro transition costs and recommended that only 21 percent of the transition benefits should be recovered from ratepayers. The 21 percent was derived from the percentage of Technical Services costs that were charged to generation activities during the period 1996 through 1998. The Advisory Staff explained that the 21 percent recovery properly allowed for the generation-related work that was no longer necessary. The Advisory Staff stated that closure of Technical Services was not related to restructuring as asserted by the Company in its filing. Rather, the decision was the result of the Company's assessment that Technical Services no longer fit strategically in CMP's business plans. The Advisory Staff used the 21 percent allocator to reflect the categories of work performed by Technical Services. In addition to generation-related work, Technical Services did work for T&D operations as well as work for entities not affiliated with CMP. The Bench Analysis notes that the T&D utility will continue to require the services that Technical Services used to perform and that those costs remain in the revenue requirement. The

Bench Analysis also points out that the majority of Technical Services employees did not lose their jobs, but were hired by the new owners of Technical Services.

In its Response to Intervenors Testimony and the Bench Analysis, CMP claims that the Advisory Staff's contention that the decision to sell Technical Services was a result of a change in business strategy is "unsupported by any facts in the record of this proceeding." CMP also explains that according to Commission Rules, the terminations are presumed to be related to restructuring since they occurred between January 1, 1998 and March 1, 2000. The Company, however, admits that it will continue to need T&D engineering work, and that those services can be acquired more cheaply on a contract basis than by maintaining Technical Services as a division.

b. Analysis and Conclusion

Determining the amount of the transition benefits associated with Technical Services to allow in the T&D revenue requirements is linked to whether the layoffs, and hence the transition costs, resulted from the State's move to retail access to generation services.

CMP characterizes as unsupported the Advisory Staff's statement that CMP sold Technical Service because it no longer fit strategically into CMP. At the technical conference, however, Company witness Dumais responded to the question of why E-Pro was sold, as follows:

> Let me just point you -- I'll answer, but let me also point you to a data request. IECG 01-04. The Technical Services business unit provided significant services to CMP's generation function. So, after we divested, CMP Group made a decision that the Technical Services group was no longer an entity that fit strategically into where CMP Co., actually CMP Group, was going. So, that's why we sold out.

August 10, 1999 Technical Conference Transcript Pages Z-123 and Z-124.

CMP argues that the sale of generation assets resulted in a significant loss in economies of scope and economies of scale for Technical Services. The E-Pro Technical Services Division, which CMP eliminated through the sale to former E-Pro employees, consisted of 39 employees. Thirty-six of those employees went to work for the new E-Pro. As the adjustment proposed by the Advisory Staff indicates, 79 percent of Technical Services operations were non-generation related. CMP has retained in T&D revenue requirements the E-Pro costs allocated to the T&D function on the theory that such functions will still be necessary. Given the size of the E-Pro division and the small amount of costs attributable to generation, we do not believe that it was necessary to eliminate the entire E-Pro division in order to eliminate the generation-related costs.

The Company correctly points out the Commission's Employee Transition Benefits Rule provides that absent just cause, a layoff which occurs after the effective date of the promulgation of our Rule will be deemed to have been due to retail competition. MPUC Rules ch. 303, § 2. As counsel for the Company recognized at the hearing on this matter, the presumption created by our Rule is a rebuttable one. In this instance, we find that sufficient evidence has been presented to rebut the presumption created by Chapter 303. We therefore conclude that it would be improper to treat the elimination of all E-Pro positions as being caused by the sale of generation assets. We agree with the Advisory Staff that 21 percent of the transition is the appropriate amount for CMP to recover as restructuring related costs from its T&D ratepayers.

3. FPL

a. Positions Before the Commission

As part of its Phase II filing, the Company requested that it be allowed to recover in rates all costs for the Early Retirement Benefit Enhancements (ERBE), including the Enhanced Pension Benefit (EPB), Permanent Eligibility Enhancement (PEE) and Post-Retirement Medical Benefit (PRMB), for all employees who transferred to FPL. The Company noted that even though, under the terms of the Asset Sale Agreement, employees who transferred to FPL would receive recognition of their CMP service under FPL's benefit plans thus assuring that there would be no disruption in benefit accruals for employees who continue their careers at FPL, transferring employees would be protected only as long as they were employed by FPL. The Company argues that, given the uncertainties associated with continued employment with an unregulated entity, provision of benefits to transferred employees was justified. In addition, the Company notes that if employees transferring to FPL were not allowed the same protection as those who chose to retire, an incentive would have inadvertently been created to retire instead of continue employment with FPL.

In compliance with the Commission's Phase I Order, the Company submitted a copy of its Memorandum of Understanding with the union representing its generation-related employees, the International Brotherhood of Electrical Workers (IBEW or Union), regarding the provision of employee severance benefits. The Company acknowledges that recovery of EPRB costs was not a condition of the payment of benefits.

In the OPA's response to the Company, OPA witness Jim Dittmer argued that in light of the tight labor market, as well as the Company's statements that such workers received relatively low wages, it was questionable whether the Company should recover any termination benefits beyond those mandated by the Restructuring Act since even laid off workers would be able to find other suitable employment relatively easy. Mr. Dittmer, however, did not recommend that the Commission reverse its prior decision to allow recovery for enhanced benefits for laid off employees. He did recommend, given the circumstances cited above, that ratepayers not be required to fund the costs of the ERPB for employees who transferred to FPL. Mr. Dittmer noted that it was difficult to envision any undue harm for such employees since they were entitled to have their years of service transferred to FPL for purposes of calculating pension and PRMB benefits. Mr. Dittmer also argued that providing the ERPB to all employees made continued employment with FPL less attractive and, thus, provided a disincentive for continued employment rather than an incentive as argued by CMP.

In its Bench Analysis, the Advisory Staff separately analyzed the pension and enhanced medical benefit issue and made differing recommendations based on its analysis. With regard to the EPB and PEE costs, the Advisory Staff noted the following language of the Commission's Phase I Order:

> Whether the costs associated with the ERBE program are ultimately recoverable from ratepayers may be affected by the agreement(s) between the Company and the International Brotherhood of Electrical Workers (IBEW) at the time we approved the Company's plan. Therefore, we will require CMP to provide a copy of the signed agreement(s) to us during the Phase II portion of this proceeding. The Company and the IBEW may also provide any other information related to the intent of the parties regarding Commission approval of the Plan. Among other matters, we wish to know whether Commission approval of the recovery of costs associated with the Plan was a requirement for the agreement to take effect.

Phase I Order at 24.

Based on its reading of the Memorandum of Understanding between the Company and the IBEW, which did not make receipt of the EPB and PEE benefits contingent on ratepayer reimbursement, the Staff recommended that ratepayers not be required to bear the costs of the EPB and PEE benefits packages for workers who were transferred to FPL. The Bench Analysis reasoned that since transferred workers would receive full credit for service, payment of the EPRB was not necessary to protect transferred employees from undue harm. This would not create a disincentive to accepting employment with FPL since ERBE benefits would not extend to workers who were transferred to FPL but who refused employment.

The Bench Analysis reached a different conclusion, however, regarding the PRMB package. The Staff first noted that the Commission specifically allowed CMP to present additional evidence as to what additional benefits employees who transfer to FPL will receive as a result of the PRMB and whether these benefits are necessary to prevent employees who transfer from being unduly harmed. As part of its Phase II filing, the Company clarified that the PRMB package allowed employees to participate in the Company's medical program after retirement if their age and years of service equal 70 as of December 31, 1998. Under the Company's existing medical benefits program employees are eligible for benefits if upon retirement they meet "modified rule of 85" (55 years of age with 30 years of service with a sliding scale for service as the employee ages). The FPL post-retirement medical package was based on the same modified rule of 85. Under the terms of the Asset Sale Agreement (ASA), CMP was required to transfer to FPL funds for FPL's recognition of CMP service for purposes of determining eligibility for post-retirement medical benefits. Since such payments were necessary to ensure that employees who transferred were in as good a position with their new employer as they were with CMP, the Commission allowed the Company to recover such costs from the asset sale proceeds. Phase I Order at 76. During the discovery phase of this case, the Advisory Staff learned that FPL did not give credit to employees who received the PRMB and that the amount that CMP transferred to FPL for FPL's post-retirement coverage under medical benefits would have been higher were it not for CMP's PRMB. Therefore, the Advisory Staff recommended that although the PRMB package, which provided additional benefits to transferred CMP employees, was not itself necessary to prevent undue harm, CMP should be allowed to recover the costs that CMP would have otherwise had to pay FPL for recognition of service for post-retirement medical benefits.

CMP responded that the Advisors' recommendation was based on a misinterpretation of the Commission's Order. Citing sections of the transcript from the Commission's deliberations of the Phase I Order, the Company argues that the Commission did not intend to disallow recovery of the costs but rather wanted to review the agreement between CMP and the IBEW to make sure there was nothing in the agreement to cause it to reach a contrary result. The Company claims that:

> the Advisors, however, twist the Commission's desire to review the agreement between CMP and the IBEW around 180 degrees; in other words, they suggest that the Commission determined that, if the labor agreement did not condition payment of the benefits to employees on ratepayer reimbursement the Commission, therefore, would not allow recovery of these costs from ratepayers.

In support of its position, the Company provided a detailed chronology of the development of its Employee Transition Plan, noting the following five objectives which went into developing the plan:

- to ensure that any employee who transferred to a buyer of generation assets could do so with full credit for CMP service;

- to provide the five mandatory benefits to <u>any employee</u> who was displaced;

- to protect the retirement benefits of employees who were late in their careers;
- to ensure that the divested assets' value was maximized by providing incentives for employees to move with the assets; and,
- to effectively manage the costs of the ETP.

The Company also argued that if extended benefits were only offered to employees who were laid off, as proposed by the Advisory Staff, there would have been a perverse incentive for employees who wished to receive such benefits to intentionally blow their interviews with FPL to ensure that they did not receive an offer of employment.

The IBEW, through Robert Dodge, Assistant Business Manager, also responded to the Bench Analysis. Mr. Dodge noted that the IBEW had two major goals for Maine's restructuring legislation. One was the inclusion of certain mandatory benefits for workers who were laid off, and the second was the inclusion of language that permitted the enhanced early retirement benefits in the transition plan. Mr. Dodge noted that the Union was worried that after the assets were sold the buyer would take advantage of the experience of their members, then downsize, which would prevent members from accruing benefits during the crucial final years.

b. <u>Analysis and Conclusion</u>

Given the controversy surrounding this issue and the dispute over the meaning of our Phase I Order, it would be helpful first to review the Restructuring Act's provisions concerning severance benefits, the provisions of our rules implementing these sections of the Act, our approval of CMP's Employee Transition Plan and our Phase I Order. Section 3216 of the Act provides that each investor-owned utility must, prior to the start of retail access, develop a plan which provides for retraining, the retention of fringe benefits, and the payment of two weeks' pay in severance benefits for each year of full-time employment for workers "laid off" due to retail competition. The statute also states that the plan may include provisions for providing early retirement benefits. 35-A M.R.S.A. §3216(2). Finally, the statute contains the following language:

> **Cost recovery.** The commission shall allocate the reasonable accrual increment cost of the services and benefits required under this section to ratepayers through charges collected by the transmission and distribution utility.

35-A M.R.S.A. § 3216(5).

On March 12, 1998, we approved CMP's employee transition plan finding that it was consistent with the requirements of Section 3216. In making this finding, however, the Commission specifically stated that:

> We have reviewed CMP's proposed plan and find that it is consistent with the statutory requirements of Section 3216. This finding should not be construed as a finding that all of the costs associated with the proposed Plan will be recovered from ratepayers pursuant to Section 3216(5). While Section 3216(5) requires recovery of the reasonable costs of those benefits mandated by the statute from ratepayers, recovery of the costs of any benefits which exceed the statutory requirements will be determined either in the rulemaking on this issue or in an appropriate ratemaking proceeding.

Central Maine Power Company, Request for Approval of Employee Benefits Plan, Docket No. 98-050, Order (Mar. 12, 1998). Our subsequently adopted rule on employee benefits provides that an electric utility employee transition plan may include provisions for the portability of accrued retirement benefits, early retirement benefits and other discretionary benefits. MPUC Rules, ch. 303 § 3(B).

In our Phase I Order, we set forth the "undue harm" standard to determine whether discretionary benefits should be recovered from ratepayers. Under the undue harm standard, we concluded that it was reasonable to require ratepayers to pay for benefits beyond those required by Section 3216 where the utility has demonstrated that its employees will be unduly harmed if additional benefits are not provided. We believe this undue harm standard is satisfied and ratepayer recovery warranted for costs associated with the EPRB program for those employees who were actually laid off as a result of CMP's asset sale. In *Bangor Hydro-Electric Company, Request for Approval of Employee Transition Plan for Benefits and Services,* Docket No. 98-700, Order at 3 (Mar. 30, 1999), we held that the term "laid off" within the context of the mandatory benefits provisions, did not cover employees who were transferred to the new owner of the generation assets. We would not view those employees who were transferred but did not accept such transfer as being "laid off" for purposes of deciding whether the discretionary benefits should be paid by ratepayers.

Consistent with our undue harm standard and the provisions of Chapter 303, which allow for ratepayer payment of costs associated with portability of benefits, we allowed the Company to deduct from the asset sale proceeds the amount paid to FPL at the time of closing for these costs. At the time of the Phase I decision this was estimated to be $1.0 million. The actual cost, based on the actuarial calculations performed at closing, was $2.2 million. Under the terms of the asset sale agreement, FPL was not required to give service credit for its medical retirement benefits program, and CMP was not required to pay for such credit for those employees who accepted CMP's PRMB package. CMP clarified in this case that it had calculated this amount to be $2.1 million. We agree with the Bench Analysis that portability of service credits for medical retirement benefits was necessary to prevent undue harm to employees who transfer. Therefore, we conclude, regardless of whether it was necessary to provide *enhanced* post-retirement medical benefits, that ratepayers should pay for those costs otherwise allowable and avoided by CMP's enhanced benefit package.

This leads us to the question of whether it was necessary to provide the EPB, PEE and enhanced PRMB to employees who transferred to FPL, including those who were offered employment and refused it, to prevent undue harm. Both the Company and the IBEW identify the harm targeted by the enhanced programs as the increased risk that transferred employees will lose their jobs in the unregulated competitive generation market. While we recognize there is a risk that FPL will curtail its Maine operations, it cannot be said with certainty that at some future point, due either to changes in the wholesale generation market, technological changes, or the shift towards incentive regulation, CMP itself would not have modified its generation operations resulting in lay-offs of generation-related employees. Thus, the extent to which there is an increased risk of harm to CMP's transferred workers is uncertain.

In deciding who should pay for the discretionary benefits in question, we believe that the remarks of Mr. Dodge of IBEW are particularly on point. In concluding , Mr. Dodge noted:

> In our view, CMP has provided Union members with well-earned and well-deserved benefits and the Company should be able to recover the costs of these benefits from its customers who have benefited both from our long years of excellent service and from the high price FPL paid for the generation assets, a price that our members helped to create by operating the generating assets very effectively.

We agree with Mr. Dodge that ratepayers have benefited from the efforts of CMP's generation-related employees. We believe, however, that CMP's shareholders have also benefited from such efforts. Those benefits would include increased profitability between rate cases and during the current ARP, and also the increased value shareholders themselves have recognized as a result of the asset sale. Therefore, we would not view it as unreasonable to require shareholders to at least partially fund the payment for discretionary benefits for their long-time, loyal employees even if such costs, as a matter of discretion, could be included in rates. It is in this discretionary context that we asked the Company to provide its agreement on the IBEW discretionary benefits. The agreement clearly does not condition payment of benefits on recovery in rates.

Given the possibility of harm to CMP's longtime employees and the benefits those employees have provided both to Company and its shareholders, we believe that it is reasonable for the Company and its ratepayers to share equally in the costs of funding the EPB and PEE benefit packages for employees who transferred to FPL or were offered a transfer to FPL but refused, as well as the remaining $300,000 in PRMB costs. This results in approximately[1] $2.4 million of such discretionary costs being borne by shareholders and $2.4 million being borne by ratepayers.

C. Amortization and Deferrals

OPA witness James Dittmer recommends that the recovery period of certain CMP deferred costs should be longer than the recovery periods recommended by the Company. Determination of the recovery period for deferred expenses is a matter left to the discretion of the Commission in setting just and reasonable rates, since, in a present value sense, ratepayers and shareholders should be indifferent. In choosing recovery periods, the Commission must weigh such considerations as the total change in revenue requirement, the nature of the expense deferred, and the period over which ratepayers will benefit from the deferred expense.

1. Ice Storm Damage Expense

CMP deferred $50.7 million in incremental costs as a result of the 1998 ice storm service restoration effort. The Company received approximately $19.6 million from the Department of Housing and Urban Development as federal disaster relief funds in reimbursement for costs incurred to repair the ice storm damage. CMP also reduced the total deferred expense by $800,000 received by the Company from Bell Atlantic as reimbursement for line clearance restoration work performed by CMP on behalf of Bell Atlantic. A dispute remains between CMP and some independent telephone utilities for reimbursement of CMP for line clearance work performed on behalf of the independent telephone companies. CMP is working to resolve the dispute and hopes to receive monetary reimbursement from the independent telephone companies in the future.

CMP proposes to recover the approximate $34 million of deferred ice storm restoration costs over two years, a recovery period suggested by the Commission in the Phase I Order. Mr. Dittmer recommends a five-year recovery period, pointing out that the amount of federal reimbursement was expected to be higher when the Commission decided Phase I. Mr. Dittmer asserts that the revenue requirement impact of a two-year recovery period amounts to more than $18 million annually, an amount significantly larger than the annual amount anticipated at the time Phase I was decided. Mr. Dittmer also argues that a two-year recovery is contrary to Commission

[1] Based on the information provided in Phase II of this case, it is not possible to distinguish employee transition costs associated with employees who were offered but refused, a transfer to FPL from the costs of benefits for employees who were laid off. As part of its Phase II-B filing, CMP should clearly separate such costs.

precedent regarding significant storm damage expenses, specifically the recovery of the April 1987 flood expenses (a ten-year period). Mr. Dittmer accepts that all parties desire to recover such costs in a reasonably short period of time and believes that a 5-year recovery period, which produces an approximate $7.3 million annual revenue requirement impact, better achieves all objectives.

CMP responds to Mr. Dittmer that the Commission should allow the quickest recovery possible that does not result in adverse rate impacts. CMP argues that an overall 10% price reduction could still result even with a two-year recovery period of deferred ice storm expenses. Consequently, in CMP's view, a 2-year recovery period would not produce unacceptable rate impacts.

We stated in our Phase I Order that we may reconsider our decision for a 2-year recovery period after the federal reimbursement is known. The federal reimbursement was considerably larger than the $2.2 million initially announced by the Department of Housing and Urban Development, but considerably smaller than the 75% of ice storm costs expected by CMP when legislation was enacted by Congress. To balance the concerns raised by CMP and Mr. Dittmer, we find it proper to extend the recovery period by one year, so that the ice storm costs will be recovered over three years. We also direct CMP to defer any reimbursement from the independent telephone companies until the next time T&D rates are adjusted and the reimbursement can be factored into the recovery.

2. <u>DSM Deferred Costs</u>

Historically, DSM "hard costs" have been deferred in between rate changes. Upon a rate change, the deferred hard costs have been recovered in rates over a 10-year period. In addition to hard costs, CMP incurs "soft" or ongoing costs that are administrative in nature or associated with DSM without determinable savings. With each rate change, an ongoing level of soft DSM costs was reflected in rates. CMP was permitted, however, to defer the difference between the actual amount of soft DSM costs incurred from the amount that was reflected in rates. CMP proposes no change in the recovery of hard costs incurred prior to 1999, all of which are already reflected in rates. For projected 1999 DSM hard costs, CMP proposes a 3-year amortization period. For the reconcilable, or soft DSM costs, projected to be unrecovered at March 1, 2000, CMP also proposes a three-year amortization period. CMP's reasons that the relatively short recovery period will occur with a 10% overall rate decrease, such that the short recovery period avoids adverse rate impacts.

Mr. Dittmer argues that CMP has not justified a departure from the typical 10-year recovery period of the 1999 hard costs. Mr. Dittmer also argues that a 3-year recovery period of the reconcilable DSM costs produces unacceptable rate impacts such that the recovery period should be extended to five years. The reconcilable DSM costs are projected to be $16.8 million as of the beginning of the rate year. Mr. Dittmer concedes, however, that if updates in this proceeding support the conclusion that retail customers are likely to experience significant savings over current rates, then at that time, he could accept a 3-year amortization period for the reconcilable DSM costs.

We agree with CMP that a 3-year amortization period for reconcilable DSM costs is proper. The revenue requirement impact is not substantial. Even at three years, we expect ratepayers to receive significant rate reductions.

The revenue requirement impact of CMP's proposed 3-year amortization of 1999 DSM hard costs is slightly more than $1.0 million. The revenue requirement of the 10-year amortization of pre-1999 hard costs is approximately $1.4 million. While we agree with Mr. Dittmer in principle that such hard costs have been and should otherwise remain to be recovered over ten years, the amount is too small to justify a separate 10-year recovery period. We will permit CMP a recovery period for its 1999 DSM hard costs over the same 3-year period as the reconcilable DSM costs.

3. Deferred Liabilities for the Post-Recovery Period

Mr. Dittmer recommends that the Commission order CMP to create a deferred liability upon termination of the recovery periods for CMP's deferred ice storm and DSM expenses.[2] Even assuming Mr. Dittmer's longer recommended recovery periods of five years, CMP's revenue requirement would be reduced by approximately $11 million at the end of five years. CMP objects to Mr. Dittmer's recommendation because it amounts to single issue ratemaking, that could be justified only if CMP is overearning at the time the recovery period terminates. As there is no basis to decide now that CMP will be overearning when the recovery periods terminate, CMP asserts that Mr. Dittmer's proposed "regulatory mechanism" to remedy overearnings is not proper and should not be adopted.

We agree with Mr. Dittmer that deferral removes these category of expenses from the effects of regulatory lag normally encountered between rate cases, and therefore equally justifies a deferral of the rate impact of the termination of the deferred expense recovery period. We expect either a traditional rate case or an incentive ratemaking proceeding for CMP before the termination of the deferred expense recovery periods. The termination of the deferred expense recovery periods could be factored into a productivity offset or as a negative exogenous cost as part of a rate cap plan, or the recovery period could be adjusted as part of setting new rates, or could be factored into an attrition adjustment. However, unless the termination of the recovery of deferred ice storm and DSM expenses is adjusted for in a future rate case or incentive rate plan, CMP shall defer the rate impact of the termination of these deferred expense recovery periods.

[2] Alternatively, Mr. Dittmer recommends that the Commission order a rate reduction of the revenue requirement reduction brought about by termination of the deferred expense recovery periods.

D. Authority to Defer Additional Expenses

In its Phase II filing, CMP requested Commission approval of several accounting orders. Specifically, CMP seeks to defer the effect of changes in NEPOOL prices and tariffs occurring beyond the final update in this proceeding. CMP also seeks to defer any severance payments occurring after June 25, 1999 made to employees terminated due to retail competition.[3] Finally, CMP requests authority to defer costs expected to be incurred in the cleanup of transformers pursuant to L.D. 665, passed in the most recent legislative regular session.

Mr. Dittmer does not oppose the Company's request to defer expenses related to the transformer cleanup. He does oppose CMP's request to defer changes in NEPOOL prices, and costs related to post-June 25, 1999 severance payments. In addition, Mr. Dittmer recommends termination of the currently approved deferral accounting of CMP's electric life program (ELP).[4]

1. NEPOOL Price Changes

Mr. Dittmer opposes deferral accounting for NEPOOL costs because, in his view, CMP did not demonstrate that such costs are likely to be significant enough to warrant such treatment. In addition, Mr. Dittmer argues that there are significant offsets to any increased NEPOOL costs, such that CMP's earnings will not be adversely affected. CMP explains that Mr. Dittmer's objection is off point. The Company argues that its deferral request is to avoid the possibility of multiple price changes in any one year, in order to capture the effect of changes in FERC regulated transmission rates without the need to change retail rates at the same time FERC changes transmission rates. CMP explains that pursuant to FERC Order No. 888, retail end use customers must take transmission service directly under the FERC-approved open access transmission tariff (OATT) once retail access occurs. Moreover, the OATT that will be effective on March 1, 2000 will be replaced with a new OATT rate on June 1, 2000. CMP states that its request for deferral is an accommodation for having one price change per year for retail customers.

The Commission has opened an Investigation of Retail Electric Transmission Services and Jurisdictional Issues, Docket No. 99-185. That investigation has confirmed the validity of CMP's statements concerning FERC's jurisdiction and

[3] The Phase I Order authorized deferral of severance costs calculated through June 25, 1999.

[4] Mr. Dittmer also proposes the termination of deferral accounting for CMP's rate effective period DSM program. He cites a data response from CMP that agrees to this termination. As CMP's comments and response to intervenor testimony did not object to Mr. Dittmer's recommendation nor question his interpretation of CMP's data response, we assume that there is no dispute as to Mr. Dittmer's recommendation concerning rate effective DSM costs.

FERC's timetable for retail transmission rate changes. We agree with CMP that price changes should be made only once a year. We will wait, however, for further developments in the Docket No. 99-185 investigation (for instance, a determination of whether this Commission will allocate costs between transmission and distribution effective with the June FERC transmission rate change) before we decide what, if any, deferral orders are necessary to maintain a once-a-year price change policy.

2. Severance Payments after June 25, 1999

Mr. Dittmer opposes deferral of severance payments made to employees after June 25, 1999, because he argues that CMP has not demonstrated that such severance payments are likely to be significant enough to warrant deferral. He argues further that any severance payments for terminated employees should be offset by a resulting reduction in labor costs.

We agree with CMP that 35-A M.R.S.A. § 3216(5) requires the Commission to "allocate the reasonable accrual increment cost" of severance benefits to ratepayers through T&D rates. As CMP is statutorily authorized to seek recovery of such severance benefit costs in rates, it seems proper to permit CMP to defer these costs for accounting purposes. It does not make sense to require CMP to expense such severance costs when incurred and yet permit CMP to later seek recovery of those costs. Therefore, we will authorize CMP to defer the severance benefit costs incurred subsequent to June 25, 1999 and otherwise authorized for recovery by our Order here. Our view is that to "allocate the reasonable accrual increment cost of [severance] benefits" means that severance benefits should be offset by reduced rate year labor costs, as Mr. Dittmer suggests. Accordingly, CMP's deferral of severance costs should be on a net-of-labor cost savings basis.

3. ELP Costs

Mr. Dittmer asserts that deferral accounting of ELP program costs should be eliminated because such costs have not fluctuated greatly and thus deferral is no longer warranted. We agree with CMP that the nature of the ELP program costs and revenues causes us to continue the deferral accounting, even accepting the factual validity of Mr. Dittmer's argument. Because of the social ratemaking nature of the ELP program, we wish to assure that customers only pay for costs that actually are incurred and that shareholders receive recovery for any costs that are incurred.

E. Attrition

1. Growth of Expenses

a. Background

In Phase I of this proceeding, we undertook an extensive review of attrition as it was expected to affect increases in CMP's costs from the 1996 test year to the rate year. With regard to O&M expenses, we increased CMP's test year expenses which were not otherwise projected to rate year levels by the Company's forecasted growth due to inflation less a one percent annual productivity offset. We also adjusted certain expenses to account for growth in the number of customers. In the current phase of this proceeding, CMP has proposed to update the rate of inflation and the growth in customer numbers. In addition, CMP has sought to separately adjust payroll expenses, medical insurance expense and pension expense to rate year levels rather than include them as part of the overall growth adjustment as was done in Phase I.

In the following paragraphs, we address the Company's proposals to separately adjust payroll and medical expenses and the arguments raised in opposition to those proposals. Consistent with our decision to recognize actual medical insurance premiums, as discussed subsequently, we have accepted the Company's update to reflect the reduced level of pension costs for the rate year. We also accept the updates to reflect adjusted inflation levels and customer growth.

b. Payroll Expense Adjustment

i. Positions Before the Commission

In CMP's Phase II filing, the Company proposed to increase its O&M payroll expense by $6.627 million to recognize actual and projected cost increases through the rate year. The CMP adjustment differs from the manner in which the Commission decided the recovery of increases in payroll costs through the rate year in Phase I of this docket. In the Phase I proceeding, the O&M payroll expense was included in the total O&M expense amount to which an attrition growth factor (inflation less productivity) was applied. CMP argues that the application of the attrition factor would not allow it to fully recover its payroll costs. As a result, CMP has proposed an adjustment to separately escalate payroll expenses at an annual rate of three percent. In support of its position, CMP asserts that its payroll costs per employee have been increasing at a rate in excess of three percent per year and that employee levels have remained constant.

The OPA is opposed to the adjustment made by CMP to reflect the three percent annual increase in payroll expense. As stated by OPA witness Dittmer:

> in Phase I of this docket, some elements of CMP's T&D cost of service were specifically projected or estimated for the rate year. However, for "all other" O&M expenses the Commission approved a methodology for developing an attrition adjustment wherein a recent-actual/DRI-forecasted GDPPI-growth-rate-less-productivity-offset factor was applied to the "all other" category of O&M expenses to arrive at estimated rate year levels. In Phase I CMP proposed, and this Commission accepted, including labor and health insurance costs in the "all other" category of O&M expense.

> Accordingly, I believe it is equitable and consistent with the Commission's Phase I order to apply a general-inflation-less-productivity-offset factor to an "all other" category of expenses *that includes labor and medical insurance.*

(emphasis in original)

In addition, the OPA points out that CMP should not be permitted to selectively adjust cost of service components that the Company believes will grow at a rate higher than the attrition factor. According to the OPA, due to the abbreviated review period, little is known about the other components of CMP's O&M expenses to enable a conclusion to be made about the growth in CMP's costs.

In the Bench Analysis, the Advisory Staff disagreed with CMP's adjustment to increase payroll expense using the three percent escalation rate. The Advisory Staff explained that the attrition analysis considers costs that grow at rates that are both above and below the rate of inflation. Therefore, removing certain cost components to reflect a different growth rate would misstate the overall level of attrition. The Advisory Staff provided an analysis which showed that CMP's O&M expenses had actually declined for the 1996 to 1998 period. Also, the Advisory Staff points out that CMP's analysis, which was used to demonstrate that cost recovery would be inadequate if the Commission's decision in Phase I were applied, assumes a constant level of employees. Advisory Staff concludes that by not capturing the decrease in employee levels, CMP's wage claim is overstated.

CMP, in response to OPA and the Advisory Staff, presents its own analysis of the trend in O&M expenses. CMP criticizes Advisory Staff's analysis for not including FERC Account No. 935; for not removing all transmission-related expenses for the rate year; and for not considering the impact of removing expenses related to the wholesale/retail function. According to the Company's analysis, the trend in O&M expenses was a growth rate of 2.11 percent, and CMP claims this directly contradicts the information presented in the Bench Analysis.

ii. Analysis and Conclusion

In the Bench Analysis, the Advisory Staff presented an analysis showing that the trend in CMP's non-labor O&M is less than the rate of inflation. CMP has attempted to show that the data presented by the Staff are flawed and lead to the wrong conclusion about its cost trend. However, when the Advisory Staff's analysis is revised for the three specific criticisms that CMP outlined in its Comments in Response to Intervenor Testimony and Bench Analysis, the conclusions reached by the Advisory Staff are still valid. The primary reason CMP's analysis results in a trended growth rate of 2.11 percent is its inclusion of Outside Services. Both OPA and the Advisory Staff identify the fact that the Company incurred large non-recurring costs in this category of expenses to prepare for the Year 2000 information system problem and to prepare for retail competition. In fact, CMP admitted it has had large expenditures in this area and that the expenditures will not continue indefinitely. The inclusion of Outside Services by CMP is the biggest difference in its analysis in comparison with the Advisory Staff's analysis. Since the 1998 Outside Services expenses do not reflect the normal ongoing level of expenses, they should be removed from the analysis because they create a distortion of the cost trend. Another reason why Outside Services should be removed is that even if we recognized the costs related to the preparation for Year 2000 and competition as recurring costs, those costs would not be incurred at the 1998 level. Hence, the cost trend will be affected.

A second flaw on CMP's analysis is found in its assumption that employee levels have remained constant at the 1996 level, when, in fact, they have declined. CMP's analysis compares the cumulative payroll increase through the rate year based on the factor allowed in the attrition analysis and its three percent growth rate. The Company then concludes that the attrition study method would result in an inadequate recovery of payroll costs. However, since the payroll costs based upon the three percent projection is based on a constant level of employees, rather than reflecting decreases in employees that have occurred, the results overstate the level of payroll growth.

As a general matter, attrition looks at a broad category of costs and applies an overall growth rate to all cost items in the category. In this analysis, CMP has decided to separate a cost whose stated rate of growth is higher than the attrition factor. When properly analyzed, however, that rate of growth is less than the growth rate assumed in the broader approach.

Noting that actual 1998 plant additions fell well below those incorporated in the original attrition analysis in Phase I of this proceeding, the OPA also points out that recognizing the reduction in plant additions would reduce depreciation expense, return requirements and taxes. This is further evidence of the problems created by attempting to selectively update certain items which fall outside the trends originally expected in the overall level of costs.

Given CMP's cost trend, we believe it is inappropriate to separately remove payroll expenses from the attrition analysis and to separately escalate those expenses as done by CMP. We have removed the Company's payroll adjustment of $6.6 million and included payroll in the O&M expenses included in the attrition analysis.

c. <u>Medical Insurance Expense</u>

i. <u>Positions Before the Commission</u>

CMP proposed an adjustment to increase its O&M expenses by $1.5 million to recognize actual and projected cost increases through the rate year. Like the adjustment to payroll expenses, CMP's adjustment to medical expenses also differs from the Commission's decision in Phase I of this proceeding. In Phase I, medical expenses were included in the attrition analysis to which the attrition factor was applied. According to CMP, increases in medical insurance will grow at a rate higher than that which is reflected in the attrition analysis. As a result, it is necessary to separately adjust medical expenses to allow the Company to fully recover its costs. In its filing, CMP proposed an adjustment to escalate medical expenses by nine percent annually through the rate year. CMP's nine percent escalation rate was based upon two studies which indicated employers' expectations of the growth in medical expenses.

Both the OPA and the Advisory Staff's Bench Analysis opposed CMP's escalation of medical expenses. The OPA addressed its concern about CMP's escalation of costs in conjunction with its discussion of the payroll cost escalation. That discussion already been summarized in this decision, and thus, it will not be repeated here.

According to the Bench Analysis, CMP's adjustment was not properly supported. The Company had based its adjustment on surveys of employers' expectations without any explanation of the cause for the increases or whether they applied to CMP.

In CMP's Response to Intervenor Testimony and Bench Analysis, CMP presented a report from Actuarial Sciences Associates, Inc. (ASA) which concluded that CMP can expect actual health care cost increases of four percent in 1999 and 7.5 percent in 2000. CMP states that the combination of the two expected cost increases results in an average medical trend rate of 5.75 percent through 2000. As a result, CMP revised its proposed adjustment to medical expenses downward by $349,000.

ii. Analysis and Conclusion

CMP has provided data which is intended to show that its medical costs are increasing at a rate higher than that which would be allowed from application of the attrition factor. One of the points made by the Advisory Staff is that CMP used cost projections that are not specific to CMP in its trending of medical expenses. In its Response to Intervenor Testimony and Bench Analysis, CMP attempts to address that problem by referring to the ASA report in which the method of projecting medical expenses is explained. Even though the premiums for 1999 and 2000 are known, CMP has not used those premiums as the sole basis of its revised medical expense adjustment. Instead, CMP has used trend rates to develop its medical expense adjustment. The Company used 1998 as the base year and applied trend rates of 4.0 percent and 7.5 percent for 1999, 2000 and 2001, respectively. With respect to the development of the trend rates, the Company states that the 1999 and 2000 premium increases had a major impact on the overall trend level, but does not explain how.

By using forecasted trends, CMP has essentially repeated the problem that the Advisory Staff identified in the Bench Analysis. It simply exchanged the nine percent trend rate in the initial filing with four and 7.5 percent trend rates. Again, the Company offers no explanation of how or why the escalation trends that are contained in Merrill Lynch/Howard Johnson data relied upon by CMP apply to the Company. Even the statement that the 1999 and 2000 premium increases had a major impact on the overall trend level creates concern about the appropriateness of the trend rate. It is important to note that the 1998 medical insurance rate was the second year of a 2-year agreement where rates were held fixed. Therefore, one can assume that the 1999 increase may have been higher than usual as the medical insurance premiums were changed to reflect current rates. The Company's information offers no explanation of how the medical insurance component of the trend rate was derived. If there is a difference between the escalation rate used in the CMP revised medical expense in the Phase II filing, other than the quantification of the rate, that difference is that CMP claims to have converted a generalized trend rate to a CMP specific trend rate.

We believe that generalized overall cost trend rates are exactly the type of trend that is captured in the overall inflation factor. As OPA and the Advisory Staff have pointed out, CMP should not be allowed to take out specific costs that are growing at rates higher than inflation because it distorts the overall inflationary impact on the revenue requirement. As stated in the Bench Analysis:

> The attrition analysis considers costs that are increasing at rates that are both higher and lower than the rate of inflation. Therefore, even if one can point to specific costs that are increasing at a rate higher than inflation, it is important to consider that there are also costs that are increasing a [sic] rate less than inflation. Hence, removing cost elements to apply a separate cost escalation misstates the overall level of attrition.

In deriving the appropriate level of medical expenses, we believe that the application of the escalation rate should be removed from the adjustment proposed by CMP. Instead, the level of medical expenses should be based on the actual known premiums for 2000.

2. Sales Forecast

a. Introduction

The Phase I Order adopted six recommendations related to the Company's sales forecast as identified in the March 1999 Bench Analysis. In its Phase II filing, the Company addressed each of the issues raised in the Order. We review each of the issues raised in the Phase I Order, and the method by which the Company addressed each issue.

b. Documentation

The Phase I Order directed the Company to provide in its forecast update more detail regarding the sales forecast results and how the forecast was developed than was contained in its December 5, 1997 filing. Order at 30-31. The Company's Phase II filing adequately satisfies the requirements of the Order regarding the need for added detail and documentation. The information and data provided in Volume 3 -- Sales Forecast were sufficient to accommodate review of the forecasting methodology relied upon by the Company and the application of the methodology.

c. Average Usage per Residential Appliance

CMP relied on an end-use modeling approach to forecast residential sales. This approach entails forecasting the number of residential appliances by type of appliance for each of 25 types, including a miscellaneous category, and multiplying the number of appliances by unit energy consumption (UEC) estimates, which characterize energy use per year per appliance, to forecast residential energy sales. The Phase I Bench Analysis noted that certain of the UECs were developed from small samples, hence calling into question the reliability of the estimated UECs developed from these samples. Additionally, several of the UECs used by CMP to forecast residential sales differed substantially from UEC estimates relied upon by other New England utilities. The Phase I Order stated that "CMP should . . . review available end-use estimates by appliance type to reconcile its own estimates with those relied upon by others." Order at 32.

To address the issues related to the UEC estimates, CMP conducted a comprehensive review of its UEC values (Sales Forecast, volume III-B, Exhibit 4, Attachment B; Richard Brown, "Review of Central Maine Power Residential Unit Energy Consumption Values"). The analysis conducted by Richard Brown, Staff Research Associate at the U.S. Department of Energy's Lawrence Berkeley National Laboratory, Energy Analysis Department, compared CMP's UEC estimates to estimates developed by other utilities, government agencies, and research organizations. Mr. Brown found that most of the UECs relied upon by CMP in developing its residential sales forecast were " reasonable and compared well to UEC estimates developed by other utilities." (Sales Forecast Exhibit No. 4, Attachment B, page 5.) Mr. Brown recommended changes, however, to four of CMP's UECs -- those for water heaters, room air conditioners, televisions, and fossil fuel heating auxiliaries. CMP incorporated the changes recommended by Mr. Brown in its sales forecast update. CMP has adequately addressed the Commission's directive regarding the UEC values used in the forecast of residential sales.

d. Residential Income Elasticity

The Company's forecast of residential sales presented in its Phase I filing included adjustments to reflect changes in the residential use of electricity resulting from changes in the real income of consumers over the forecast period. The income adjustment, however, was based on an assumed income elasticity. The Order stated that CMP should refine its income elasticity estimate based on additional research. Order at 32.

To improve its income elasticity estimate, CMP developed an econometric equation which, among other factors, related changes in residential electricity consumption to changes in real income. CMP relied on the revised estimate of the income elasticity to adjust the projected level of residential sales developed through application of the end-use methodology. CMP applied the income elasticity estimate appropriately and consistently with the manner in which the income elasticity was estimated. This issue has been adequately addressed by the Company.

e. Residential Fuel Switching

The Phase I Order directed CMP to verify its fuel switching and retention assumptions associated with its residential sales forecast. The Company updated its fuel switching and retention assumptions based on CMP's January 1999 Home Energy Survey. The fuel switching analysis performed by the Company is adequately documented in its Phase II filing (Sales Forecast, Volume III-B, Exhibit 6). This issue has been adequately addressed.

f. Customer Interviews

The Phase I Order expressed concerns regarding the method by which Company projected sales to the commercial and "other" industrial sales classes. Specifically, the Company's reliance on customer interviews for large customers combined with reliance on DRI industry output projections for the remaining customers was viewed as problematic based on the interrelationship of the DRI output projections and the customer interview information. Additionally, the customer interview information was assessed in such a way as to potentially understate future sales. The Phase I Order directed CMP to adopt an alternative forecasting approach that avoided the problems identified.

CMP took several actions to address these issues, although the forecast of commercial and "other" industrial sales was conducted in a manner much like the method used in the Company' s December 1997 filing. Specifically, the quality of the survey information underlying the forecast for the commercial and other industrial sectors does not appear to be substantially improved over the information reviewed in Phase I of this proceeding. The Bench Analysis attributed this, in part, to the bulk of the surveys being conducted prior to surveyors having fully evaluated the comments presented by the Phase I Bench Analysis.

To verify the reasonableness of its commercial sales and "other" industrial sales projections, the Company performed econometric forecasts for these two sectors. In the case of the commercial sector, sales projected using the econometric model were about two percent lower than the projection made by the Company using the DRI/customer interview approach, though it is noted that the weather-related terms in this model are misspecified. Phase II Bench Analysis at 18. For other industrial sales, the forecasts using both methods were comparable. Given these results, no adjustment to the commercial and "other" industrial forecast associated with concerns regarding the interview approach is warranted.

g. Verification of Paper Industry Projection

The Phase I Order directed CMP to verify its paper industry sales projections. Order at 34. CMP verified these projections for its update and modified its forecast to include the assumed retention of two paper mills through 2002 that were assumed would be lost as customers in the Company's December 1997 forecast. The verification and updating of the paper industry forecast have been adequately addressed by the Company.

h. Price Elasticity Adjustments

A separate issue has been identified in the Phase II Bench Analysis related to the Company's application of the price elasticity to adjust commercial sector sales. The Company's Phase II filing incorporates adjustments to residential, commercial, and "other" industrial rate year sales based on price elasticity effects. The Phase II Bench Analysis contains no recommended modifications to CMP's price elasticity adjustments for residential and "other" industrial sales, but indicates that the Company recognized only the short-term impact on sales associated with a change in price for commercial sector sales. Phase II Bench Analysis at 18-20. Because of the way in which the commercial sales econometric equation is specified, i.e., use of a lagged dependent variable as an explanatory variable, a price change in one quarter will affect usage not only in that calendar quarter but in future quarters as well. CMP only recognized the impact in the calendar quarter in which the price change occurred. By not recognizing second (and additional) round effects, the Phase II Bench Analysis contends that the impact of price reductions on changes in commercial usage is understated by the Company.[5] Phase II Bench Analysis at 19.

CMP states that " it is inappropriate when forecasting out one or two years ... to incorporate a long-run elasticity . . . ." CMP Comments in Response to Intervenor Testimony and Bench Analysis at 38. Additionally, CMP states that the econometric approach shown in the Phase II Bench Analysis is not suitable for

[5] This problem does not exist with respect to the residential sector because the residential econometric does not contain a lagged dependent variable as an explanatory variable.

application to a non-econometric model, such as CMP's model, since different business segments (e.g., public sector, not-for-profit, and private sector) will have different long-run price elasticities. CMP Comments in Response to Intervenor Testimony and Bench Analysis at 39. Finally, CMP indicates that the method used in the Bench Analysis to capture second and higher round price effects is not consistent with forecasting principles. CMP Comments at 39.

While the adjustment suggested by the Advisory Staff may have theoretical merit, the adjustment suggests a precision in the forecasting methodology (an econometric forecast based on subjective survey information) which we do not believe is present here. Therefore, rather than make the discrete adjustment suggested by the Advisory Staff, we will accept CMP's commercial sector sales forecast as part of its overall sales forecast, which the Advisory Staff agrees is appropriate.

i. Updates

The Company indicated that in December it plans to update its sales forecast for any significant changes associated with its sales to large customers. We find this to be appropriate, but given the limited time for review of this information, we direct the Company to file the full basis and all supporting information, including any updated customer survey information, at the time it makes its filing.

IV. STRANDED COSTS

A. Transitional Power Supply Costs

The Company has entered into a transitional power supply agreement with FPL to purchase the output of the divested fossil/hydro generation assets through February 2000 to meet its retail load obligation. The power supply agreement was an integral part of the generation asset sale, authorized by the Commission in Docket No. 98-058. Because the cost of power supply under the FPL agreement exceeds the Company's embedded costs had the Company continued to own and operate the units in the transition period, CMP proposes to subtract the incremental power supply cost from the divestiture proceeds. In our Docket No. 98-058 Order, we agreed in principle with CMP, but left to this proceeding to calculate the incremental amount.

In its Phase II filing, CMP calculated incremental transitional power supply costs to be $49.6 million. CMP's calculation used a November 1998 oil price forecast in its U-Plan model runs to estimate the embedded costs of CMP continuing to operate its fossil units. CMP calculated its payments to FPL for hydro generation sales assuming normal hydro conditions. At a technical conference, CMP stated that, in its view, transitional power supply costs should be based upon such estimates, making unnecessary any further updates. In the Bench Analysis, the advisors recommended that the transitional power supply calculation should be based upon actual costs of residual oil and actual hydro output, at least through the update phase of this Phase II proceeding; use of estimates for the final two months would be acceptable.

In response to the Bench Analysis, CMP agreed to reflect actual oil prices and hydro deliveries, but only if actual results were used for the entire duration of the buyback period through February 29, 2000. The calculation of the transitional power supply costs using actuals for the entire buyback period is acceptable to the Commission.

With respect to actual oil prices, CMP states that it no longer has access to oil price data for the W. F. Wyman Station since transferring those plants to FPL. Because CMP was unaware of any public filings that would provide actual monthly fuel data, CMP suggested that the Company hire an expert to estimate the actual cost of oil burned at Wyman Station and use that data to reflect actual oil prices in the transition power supply calculation.

The Commission prefers to use actual fuel prices, providing actual data can be obtained. The actual Wyman fuel data, at least for Wyman 4, should be available through mid-June from MPS, as the MPS asset sale closing occurred later than CMP's. To the extent that actual data cannot be obtained, CMP must provide support for its expert's cost estimate.

B. Non-Divested Nuclear Generating Assets

CMP has not divested its interest in the Millstone 3 and Vermont Yankee nuclear plants. CMP is required to sell the output associated with these generating assets. The actual price of CMP's bid process will be used to calculate stranded costs by subtracting the annual "revenue requirement," or costs, for each facility from the revenue received from the bid process for the output.

1. Millstone 3

The Nuclear Regulatory Commission (NRC) required the shutdown of Millstone 3 from 1996 until the summer of 1998, and the plant continues to be listed on the NRC watch list. CMP uses a financial forecast by Northeast Utilities (NU), the lead owner and operator, to calculate the operating costs for Millstone 3 for the two-year period for which the output from Millstone 3 will be sold pursuant to the Chapter 307 auction. CMP did not use an adjusted recent historical period because of a concern that a one-year snapshot coming out of an extended outage during which the plant underwent significant change may not be representative of future operating costs.

CMP and other minority owners of Millstone 3 have brought a lawsuit and arbitration proceeding against Northeast Utilities alleging negligence by NU in the operation of the plant. The minority owners identify and quantify future costs related to Millstone 3 being placed on the NRC's watch list, for which the minority owners seek recovery from NU. CMP's share of the costs, for which NU should be liable according to the plaintiffs, is $557,000 in 2000, $326,000 in 2001 and $379,000 in 2002.

Because of the operational and NRC difficulties at Millstone 3, NU's operating subsidiary, Connecticut Light and Power Company (CL&P), did not seek recovery of, and the Connecticut Department of Public Utilities Control (CDPUC) accepted for ratemaking purposes, the removal of shutdown-related expenses from the O&M costs allowed as part of the 1999 rate effective period.[6]

The Connecticut DPUC and the NRC have found the extended outage of Millstone 3 to be caused by NU's operational deficiencies. In fact, the Connecticut DPUC decided as a matter of summary judgment that the outage was caused by NU's imprudence, resulting in a denial of CL&P's replacement power costs during the outage. *DPUC Investigation into Whether Connecticut Light & Power Fulfilled its Public Service Responsibilities with Respect to its Nuclear Operations,* Docket No. 96-10-06 (Conn. DPUC, July 30, 1997). Furthermore, both the Connecticut DPUC and the minority owners found that post-outage operating costs remain higher than the operating costs would be if NU had not operated the plant imprudently. At least for 1999, CL&P agreed with the Connecticut DPUC, and in filing for 1999 rates it excluded those operating costs which were for shutdown-related activities.

Based upon the Connecticut DPUC decisions and findings and the NRC enforcement action, fines and watch list determination, the Commission accepts that the extended outage of Millstone 3 was the result of NU's imprudence and that some ongoing O&M costs result from the imprudently-caused outage. CMP, through the minority owner's lawsuit, measured the rate effective period costs caused by NU's imprudence. We will accept NU's forecast for Millstone costs for the years 2000-2001, after subtracting the minority owner's estimate of the imprudent costs.[7]

CMP asserts that the Commission should set stranded costs using actual Millstone 3 operating costs. If CMP and the other minority owners are successful in recovering costs for the period March 1, 2000 to February 28, 2002, CMP offers to defer such revenue for future stranded cost ratesetting.

We decline to adopt CMP's position. The Connecticut DPUC has already found NU's operation of Millstone 3 to be imprudent. Retroactive ratemaking inhibits our ability to wait for the outcome of the minority owners' lawsuit (and arbitration). Moreover, although there may be similar standards involved in deciding imprudence and negligence, contractual matters are at stake in the lawsuit. The minority owners could lose on contract grounds not relevant to NU's operating imprudence or negligence. Accordingly, we will calculate stranded costs by subtracting the best estimate we have for NU's imprudent operating costs.

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[6] In setting the stranded costs for CL&P and United Illuminating, the Connecticut Department of Public Utilities and Control used O&M costs of a peer group of power plants rather than NU forecasted costs for Millstone 3.

[7] Specifically, we will subtract ten-twelfths of the 2000 estimate, all of the 2001 estimate, and two-twelfths of the 2002 estimate.

2. Vermont Yankee

CMP calculates the operating costs for Vermont Yankee using the most recent financial projection supplied by Vermont Yankee. There has been some debate about whether such financial forecasts have overstated Vermont Yankee's actual expenses, but the effect on CMP's share of operating costs is much less significant because of the small ownership share of CMP. We will use Vermont Yankee's financial forecast to measure stranded costs associated with Vermont Yankee over the 2-year period adjusted as described below. CMP agreed at a technical conference to substitute the 2000 Vermont Yankee budget for the 2000 financial forecast if the budget is available at the time of the update.

CMP agrees to substitute the current decommissioning expense for the decommissioning expense contained in the financial forecast, because Vermont Yankee is not expected to seek an increase in its current decommissioning collection rate. The Commission agrees that CMP should defer the effect of any subsequent change in the FERC-allowed decommissioning collection rate, should one be implemented by FERC before stranded costs are next adjusted in rates. Similarly, payments for the Texas Low Level Waste Compact should be excluded from Vermont Yankee's operation cost at this time. CMP should, again, defer any payments actually made before stranded costs are next investigated by the Commission.

Since CMP filed its response to the Bench Analysis, Vermont Yankee has entered into a purchase agreement to sell the nuclear power plant. Closing is not expected to occur until the summer of 2000. It is not clear whether the sale will result in higher or lower stranded costs compared to the stranded costs calculated for Vermont Yankee in the non-divested, sale of output stranded cost calculation. However, if a transfer in ownership occurs before the next stranded cost investigation, CMP should defer the difference between the stranded costs for the non-divested Vermont Yankee compared to the stranded costs associated with the sale.

C. Closed Nuclear Facilities

1. Maine Yankee

The Advisors recommended that projected payments for the Texas Low Level Waste Compact and for the Spent Fuel Trust Fund be excluded from CMP's financial forecast used to calculate Maine Yankee stranded costs. The Advisors recommended that if CMP is required to make such payments, CMP should be allowed to defer those payments for future recovery. CMP concurs with the Advisors' recommendation. We also concur and adopt the Advisors' recommendations.[8]

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[8] The remaining disagreement concerning the contingency within Maine Yankee's financial forecast in "other O&M" has disappeared because Maine Yankee

2. Connecticut Yankee

CMP calculates its stranded costs associated with its Connecticut Yankee investment using financial projections provided by Connecticut Yankee. Connecticut Yankee projections include decommissioning expenses as allowed as part of Connecticut Yankee's ongoing FERC rate case, currently collected subject to refund. CMP also proposes an earnings synchronization adjustment so that stranded costs are adjusted to remove the difference between FERC's rate of return for Connecticut Yankee and the Commission's rate of return for CMP.

While FERC has not decided the pending rate case, the administrative law judge (ALJ) has issued an initial decision, the equivalent of our examiner's report. The ALJ recommended that FERC reject the entire proposed increase in decommissioning expense and thus would require full refunds back to the date FERC accepted the rate case filing. The ALJ also recommended a zero percent return on equity to account for imprudence by Connecticut Yankee in operating and shutting down the plant.

In the Bench Analysis, the Advisors urged the Commission to calculate stranded costs for March 1, 2000 to include the traditional earnings synchronization adjustment, making CMP earn the Maine Commission return on equity on its Connecticut Yankee investment, and decommissioning expense as currently reflected in FERC's rates subject to refund. However, the Advisory Staff recommended that the Commission order CMP to defer the effect, back to March 1, 2000, of any FERC settlement or decision that changes the decommissioning expense or adopts an equity return adjusted for imprudence, or makes any other cost adjustment made to compensate Connecticut Yankee ratepayers for imprudence.

In its response to the Bench Analysis, CMP objects to the elimination of the earning synchronization adjustment, even if the failure to synchronize earnings was based upon an imprudence finding by FERC. CMP did not respond to the recommendation concerning deferral of the effect of any refund of decommissioning expense.

In its exceptions to the Examiner's Report, CMP accepts the recommendations contained in the Bench Analysis, and agrees to defer the effect of FERC decisions to refund decommissioning collections or to compensate Connecticut Yankee ratepayers for imprudent operations. Now that CMP accepts the positions stated in the Bench Analysis, there is no disagreement among the Advisors, intervenors and CMP. Accordingly, we adopt the recommendation in the Bench Analysis. We will set stranded costs using the current decommissioning collections and our customary earnings synchronization adjustment. If FERC orders a refund of decommissioning

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now charges DOE litigation expenses to "other O&M" rather than spending decommissioning trust funds for such expenses.

collections (or reduced future collections due to overcollection in the refund period), or an adjustment to Connecticut Yankee's rates to compensate ratepayers for Connecticut Yankee imprudence (whether by a lower equity return or other method), CMP shall defer the effect of the FERC decision, including the reversal of the earnings synchronization adjustment if FERC lowers Connecticut Yankee's return on equity due to imprudence, back to the date such decisions are made effective by FERC.

CMP asserts that a FERC finding of Connecticut Yankee imprudence should not necessarily be applied to CMP's minority share in Connecticut Yankee. If FERC finds Connecticut Yankee imprudent, when the question of recovery of CMP's deferred Connecticut Yankee expenses is addressed, CMP will be permitted to raise its minority share argument. One factor that may be relevant to CMP's assertion that management's imprudence in operating Connecticut Yankee should not be attributed to CMP is whether CMP diligently pursued remedies against Connecticut Yankee (or perhaps NU) to compensate CMP for Connecticut Yankee's imprudence so that CMP does not need to ask its ratepayers to reimburse CMP for costs that FERC finds imprudently incurred by Connecticut Yankee.

D. Sale of MEPCO Rights

At the Phase II initial conference, the Examiners asked CMP whether any available value had been or could be created through the sale of rights CMP had with respect to MEPCO. In its Phase II filing, CMP stated that the Company did not and will not receive any available value.

CMP is a 78% equity owner in the MEPCO transmission line, but CMP did not and will not sell its ownership interest in the line. As a transmission customer, and pursuant to the terms of MEPCO's Open Access Transmission Tariff (OATT), CMP reserved 300 MW of transmission capacity on the MEPCO line on July 9, 1996, for a period of ten years. CMP states that it was the Company's intention to use this transmission reservation to service its native load obligation. Under MEPCO's OATT, CMP was paying the full firm rate, the maximum rate chargeable, for the MEPCO transmission. In its filing, CMP states that, because CMP's obligation to buy generation service ceases on March 1, 2000, CMP does not need its MEPCO transmission reservation after that date. Therefore, CMP advised MEPCO that CMP would relinquish its transmission reservation rights as of March 1, 2000. MEPCO, then offered the transmission reservation rights to Engage Energy US, L.P., the first entity in MEPCO's queue for firm transmission service.

According to CMP, neither CMP nor MEPCO could charge Engage, or any other party, more than the maximum rate prescribed under MEPCO's OATT for such service. CMP asserts that accepting bids for its transmission capacity in excess of MEPCO's maximum rate would have violated FERC Order 888. CMP received legal advice that Order 888 generally allows a transmission customer only to assign its rights to transmission at the higher of the transmission customer's cost or the transmission provider's maximum rate. Furthermore, CMP was advised that in Order 888, lost opportunity costs cannot result in a price in excess of MEPCO's maximum rate. CMP asserts that FERC further explained, in Order 888-A, that opportunity costs only include (1) increased costs associated with changes in power purchases or in the dispatch of generating units necessary to accommodate a reassignment and (2) decreased revenues resulting from the assignor's having to reduce sales of power in order to effect the reassignment. Consequently, CMP will not incur any increased costs related to item (1) nor will CMP experience a decrease in revenues related to item (2) above. In CMP's view, opportunity costs are restricted to changes in energy and capacity resulting from the reassignment and are not applicable to the transmission reservation being reassigned. In addition to CMP's reassignment of its transmission rights to Engage, Engage assumes CMP's liabilities, duties and obligation pursuant to the service agreement between CMP and MEPCO.

Bangor Hydro-Electric Company (BHE) similarly reserved 100 MW of transmission capacity on the MEPCO line on July 1, 1996. BHE included its entitlement to 100 MWs of transmission capacity on the MEPCO line in the package of generation-related assets that could be obtained through its divestiture auction. PPL Global, the wining bidder in BHE's auction, paid $89 million for the package of generation assets that included entitlement to the MEPCO capacity.

Even absent an agreement between BHE and PPL Global as to the proper allocation of the $89 million among the generation assets sold, we know that PPL Global placed some value on the transmission capacity because transfer of that entitlement was a necessary part of the purchase agreement. PPL would not close the transaction and pay BHE $89 million unless the transmission capacity was assigned to PPL.

FERC approved the generation asset sale by BHE to PPL Global. We can infer that FERC will accept a reassignment of transmission capacity entitlement as part of an overall asset sale package without requiring the purchaser of the reassignment rights to demonstrate that the transmission capacity reassignment does not involve payment of impermissible opportunity costs. Thus, by including the reassignment of MEPCO capacity as part of a total package of generation assets, BHE enabled a purchaser to place an enhanced value on the total generation asset package that included the transfer of BHE's transmission entitlement without the need to confront the question of whether the purchaser valued the transmission entitlement in a way that violated the requirements of Orders 888 and 888A.

By BHE's inclusion of its MEPCO transmission entitlement rights as part of the package of generation assets in its divestiture auction, the Commission could be certain that BHE took all reasonable steps to maximize the value of its MEPCO entitlement. As a stand-alone transaction, we know that CMP's reassignment of MEPCO transmission rights did little or nothing to mitigate CMP's stranded costs. In the abstract, by not including the transmission rights in the generation-related asset auction, CMP may have eliminated the possibility that a combined package that included MEPCO transmission rights could have brought greater value than was received when

MEPCO rights were divested separately from other generation-related assets. However, in the context of CMP's actual sale to FPL, we will not speculate whether MEPCO transmission rights would have caused FPL to pay more to CMP for the total asset package. Having analyzed CMP's transaction with FPL, including the litigation between CMP and FPL, it would not be reasonable or fair to find that CMP could have achieved greater available value from a sale to FPL that included MEPCO transmission rights.

While we have found that the results from CMP's generation asset sale and assignment of MEPCO transmission entitlements reasonably mitigated stranded costs, we emphasize that CMP, and all electric utilities, must maintain a vigorous effort to mitigate stranded costs. We believe that the Restructuring Act requires such effort. *See* 35-A M.R.S.A. § 3208(1) and (4). Even after March 1, 2000, electric utilities must continue to satisfy this obligation for the Commission to continue to impose the stranded cost burden on ratepayers.

E. Rate Setting Methodology

In Phase I, the Commission concluded that stranded costs should be set for a time commensurate with the sale of QF entitlements. Since Chapter 307 of the Commission's Rules provides for a 2-year sale period for QF entitlements and since CMP's QF costs were likely to decline in the second year, the Commission decided to levelize stranded costs revenue requirements on a net present value over the sale period (two years) to achieve an equitable and logical result.

In its exceptions, the Company argued that the levelized approach would result in the Company's under-collecting revenues in the initial year of the recovery period, which would adversely impact its financial results. While it was assumed that this financial reporting issue could be adequately addressed through the entry of appropriate accounting orders, the Company was allowed to present evidence in Phase II of this proceeding to counter that assumption.

In its Phase II filing, the Company noted that while an accounting order would alleviate the Company's concerns surrounding earnings volatility, it would require the Company to accrue uncollected revenues on its books, which would result in carrying costs on such amounts as well as carrying costs on the taxes on such revenues. In CMP's view, this would generally increase the Company's risks of collecting its costs. The Company recommended that instead of the levelization approach suggested in the Phase I Order, the Commission should, as part of its final order in this case, direct a "scheduled" across-the-board rate change to reflect the decrease in stranded cost revenue requirements.

In his direct testimony, Dr, Silkman expressed concern with both the Company's scheduled decrease methodology and the Commission's levelization approach. Dr. Silkman noted that both approaches squander the opportunity to do rate design changes without the usual adverse bill impacts.

To address the concerns of the parties, the Bench Analysis recommended that in lieu of the levelization approach suggested in the Phase I Order, the Commission adjust the amortization of the available value account in a manner that achieves the goals implicit in the levelization approach: just and reasonable stranded cost revenue requirement collection and rate stability. Thus, if stranded costs are likely to be higher in year 1 than in year 2, to avoid an overcollection of revenues and to have rates remain stable, the available value amortization would also be higher in year 1 than in year 2. Since we still do not know what the standard offer rates will be, we will not establish amortization amounts or schedules at this time. As part of its Phase II-B filings, CMP should submit a proposed amortization schedule consistent with the requirements of our Phase I and II Orders.

We conclude that the available value adjustment technique proposed in the Bench Analysis provides a flexible and fair methodology for addressing the concerns raised in our Phase I Order. We also believe that Dr. Silkman's concerns can be addressed in part of this approach. Specifically, should the Commission conclude a rate design case prior to March 1, 2001, the Commission could achieve the rate neutrality sought by Dr. Silkman simply by not implementing the scheduled available value amortization decrease.

V. STANDBY RATES

The most contentious issue in Phase II involving the design of T&D-only rates is whether T&D versions of CMP's current Rate SB and Rate O should be established. Currently, Rate SB has three components: (1) a fixed monthly standby charge of $2,000; (2) the applicable all-requirements tariff rate, with the demand charge prorated for days energy is delivered; and (3) a peak responsibility charge of $2.09 per kW-month, with an 11-month ratchet, if energy is delivered at the annual system peak. Rate O is an interruptible rate. The rate is CMP's voltage and time differentiated marginal energy cost plus an adder.

A. Positions before the Commission

In its July 1, 1999 Phase II filing, CMP did not propose T&D versions of Rate SB and Rate O. In CMP's view, the Commission's Phase I Order found that standby rates should be the all-requirements rates, adjusted to include a ratchet. CMP states that Rate SB and Rate O are primarily designed for generation service and are thus not applicable to a T&D-only utility. Additionally, CMP argues that elimination of Rate SB would not violate the "no losers" principle because no customers have taken the rate for many years. With respect to Rate O, CMP states that, consistent with the Phase I Order, it may eliminate the Rate at its option because it is a non-core rate.

CMP also proposes that customers currently taking standby service under Rate GSS be required to take service only under the T&D version of that Rate. Rate GSS is a station service rate historically applicable only to the Maine Yankee and

Wyman 4 generation facilities. CMP argues that these customers should not be allowed to take service under generally applicable standby rates because allowing this option would create rate design losers.

On August 27, 1999, the IECG filed the testimony of Richard Silkman. Dr. Silkman states that T&D versions of Rate SB and Rate O should be established to avoid violating the no losers principle. The IEPM and S.D. Warren/FPL Energy Maine agree that a T&D version of Rate SB should be available to all standby customers.[9]

Dr. Silkman responds to CMP by stating that eliminating Rate SB would violate the no losers principle even though customers have not historically taken the service, because CMP will determine discount prices by evaluating the cost of the customer's alternative self-generation option plus the cost of standby service. If eliminating Rate SB raises the cost of the customer's alternative, CMP could lower the amount of the discount, thus creating a "loser." Regarding Rate O, Dr. Silkman disputes the relevance of the designation of "non-core" as to whether a rate can be eliminated.

Dr. Silkman proposes the following modifications to establish a T&D version of Rate SB: (1) the fixed charge of $2,000 per month would remain unchanged; (2) the energy charge would continue to be the applicable unbundled all-requirements tariff kWh charge, and the demand charge in the all-requirements tariff would continue to be prorated for the number of days service is taken; and (3) the peak responsibility charge would be eliminated as related to generation capacity service.

According to Dr. Silkman, Rate O should be modified to eliminate the marginal energy charge, because CMP no longer incurs energy costs. Additionally, the adder would be modified to remove an amount representing the administrative costs of providing energy service (based on the pre-restructuring A&G costs allocated to the generation function). The remaining adder, representing the current contribution to T&D costs, would become the post-restructuring Rate O.

FPL Energy Maine, the purchaser of CMP's share of Wyman 4, argues that it is unfair, anti-competitive and inconsistent with the no-losers principle to require it to take Rate GSS when generally available standby rates exist.

In its October 12, 1999 responsive comments, CMP responded to Dr. Silkman by defending its proposal to eliminate Rate SB and Rate O. CMP states that the no losers principle does not apply to "lost opportunities," and that no customer's bill will increase as a result of eliminating Rate SB. In addition, CMP states that the rate was designed for a single customer (based on its specific load characteristics), has not

[9] In addition, Dr. Silkman argues that the standby rates adopted in Phase I are unlawful. The IEPM and S.D. Warren/FPL Energy Maine also argue that the Phase I standby rates are not cost based. The purpose of this Phase II proceeding does not include relitigating the Phase I findings.

been updated since the early 1980s, and has been ignored for almost two decades. Finally, CMP states that the continuation of Rate SB was not raised in Phase I and the Commission explicitly adopted post-March, 2000 standby rates.

At the request of the Advisory Staff, CMP did present two options for an unbundled Rate SB, but continues to argue against any adoption of a post-March, 2000 Rate SB. The first option is to leave the Rate as it is currently, because its unbundling occurs through the unbundling of the all-requirements rates that are a component of Rate SB. The second approach would be to substantially reduce the fixed charge (from $2,000 to $212) by removing its generating component and also to eliminate the peak responsibility charge. CMP states that, under either approach, standby customers would pay much less than under the approach the Commission adopted in Phase I, and the resulting windfall will be collected from other customers.

With respect to Rate O, CMP states it is specifically identified as a non-core rate and available only to a limited number of customers. CMP notes its obligation to review its non-core rates and contracts to determine if they should continue after March, 2000, and to eliminate those that no longer have a justification.

CMP argues that the customers who have historically taken service under Rate GSS should not have an option to take service under the generally applicable standby rates, because any resulting revenue loss from these customers would increase the rates of other customers.

In surrebuttal testimony, Dr. Silkman states that the Commission did not make a finding in its Phase I Order on continuing Rate SB and Rate O and that it indicated that parties could make their cases on these issues in Phase II. Dr. Silkman adds that his proposed modification to Rate SB and Rate O are consistent with the Commission's top-down methodology.

B. <u>Analysis and Conclusion</u>

As a preliminary matter, we reject CMP's argument that, as a result of our findings in Phase I, the continuation of Rate SB and Rate O are not legitimate Phase II issues. In our Order on Reconsideration in Phase I, we explicitly stated that these issues could be raised in Phase II. *Order on Reconsideration,* Docket No. 97-580 at 12-13 (June 22, 1999).

For the reasons discussed below, we make the following findings regarding standby rates: (1) a T&D version of Rate SB should be established as consistent with the no losers principle; (2) Rate O is a grandfathered core rate, and a T&D version of the Rate should be maintained; and (3) customers that can take service under Rate GSS should also have the option to take service under the generally available standby rates.

1. Rate SB

a. Continuation of Rate SB

At the outset, we note our agreement with CMP that Rate SB is an obscure, out-dated rate that was designed many years ago for a single customer, and is primarily a generation service rate. For these reasons, it is difficult to establish a sensible T&D version of the rate. However, the issue that must be addressed is whether the elimination of Rate SB would violate the no losers principle.

This is a close question. The IECG is correct that the no losers principle could be violated by eliminating a rate, even if no customers take service under that rate. The cost of standby service is part of the cost of self-generation and, as such, it impacts the level of the discount that must be offered to customers that have alternatives to purchasing their requirements from CMP. If, however, for whatever reasons, Rate SB were not historically considered a standby option by either customers or the Company, then its elimination would not violate the no losers principle, because the existence of the Rate would not have impacted any customer's rates. If Rate SB were not considered an available option, the continuation of the Rate SB would be a windfall for standby customers at the expense of other customers, thus creating rate design losers.

Although there was testimony that Rate SB was not discussed during discount rate negotiations, and, until very recently, there were no inquiries about the availability of the Rate, we cannot find that there was not an awareness of the Rate and that its existence did not impact the ultimate rate customers paid. Rate SB has been part of CMP's rate schedules for many years, and its general availability to all customers who do not purchase all their requirements from CMP is clearly stated on the tariff. It is difficult to imagine that, as a general matter, self-generating customers, who tend to be sophisticated in energy matters, would not be aware of the existence of a generally available standby rate tariff and make use of that tariff for their own advantage.[10]

For this reason, we conclude that the elimination of Rate SB would violate the no losers principle and, therefore, a T&D version should be established.[11]

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[10] For example, it is possible that Rate SB did not come up in discussions because of the availability of Rate O.

[11] In its exceptions, CMP sought Commission guidance on interpreting the Rate SB tariff language. We decline to interpret or clarify the language at this time. CMP should interpret and apply the language as it would have prior to restructuring.

2. Design of Rate SB

The next matter to be addressed is the appropriate design of a T&D version of Rate SB. In this regard, we agree with Dr. Silkman's proposal, subject to the modification that customers be required to pay for transmission through CMP's FERC Open Access Transmission Tariffs (OATTs) or its retail transmission tariff.

In summary, we conclude that the T&D version of Rate SB should have the following components.

- $2,000 per month fixed charge;
- usage paid for under the applicable all-requirements tariff, with the demand charge prorated for the number of days service is taken (for distribution level customers, only the distribution portion of the demand charge will be prorated); and
- transmission charge pursuant to the OATTs or the retail transmission charge (as applicable).

It is reasonable to maintain the $2,000 per month charge as consistent with our top-down unbundling approach. This approach removes costs from usage and demand charges, but leaves fixed charges unchanged. The fixed charge will compensate CMP for customer costs and administrative costs associated with providing standby service, and provide some additional contribution to distribution and stranded costs that other customers will pay through a non-prorated demand charge. We note that the current Rate SB tariff specifies that customers are required to pay the customer charge, as well as the demand and energy charges, in the all-requirements tariff in any month in which the customer takes service. Consistent with the no losers principle, this provision should be maintained in the new Rate SB.

For transmission level customers, we leave unchanged the Rate SB provision that requires payment of the all-requirements usage charge and prorated demand charge. This is appropriate because generation costs will be unbundled from the all-requirements tariff. Additionally, as part of the transformation to retail access, CMP will unbundle transmission costs from its all-requirements rates for transmission level customers and these customers will purchase directly from the FERC OATTs. For this reason, transmission level customers taking Rate SB should pay for transmission pursuant to OATTs. Otherwise, these customers could use the transmission system during monthly peaks while only paying a fraction of the transmission costs.[12] Moreover, FERC has asserted jurisdiction over retail transmission rates after generation

[12] We note that, under the OATTs, customers are charged for transmission only if they take service at the time of the monthly peak.

is unbundled; as a result, retail transmission service must be provided through a FERC approved tariff. Finally, adding what is in effect a transmission peak responsibility charge that is not prorated, while removing the generation peak responsibility charge which is also not prorated, is generally consistent with the no losers principle.

For distribution level customers that take Rate SB, a similar approach will be employed. The difference is that these customers would not take transmission service off the OATTs, but would pay for transmission under CMP's FERC-filed retail transmission tariff (as will be the case for all distribution level customers). Because this tariff does not prorate the demand charge, the transmission portion of the charge will not be prorated. However, the distribution portion of the demand charge (which is within our jurisdiction) will continue to be prorated. As with the transmission level Rate SB, this approach is consistent with FERC jurisdiction over transmission and with the no losers principle in that the peak responsibility charge can be viewed as replaced by the transmission charge (neither of which is prorated).

3. <u>Rate O</u>

We find that Rate O is a grandfathered core rate and direct CMP to file a T&D version of the Rate in its Phase II-B filing. The availability of the Rate should be limited to those customers who are currently eligible to take Rate O.

At the outset, we note our disagreement with Dr. Silkman that the distinction between "core" and "non-core" has no relevance in determining whether a rate can be eliminated consistent with the no losers principle. In our Phase I Order, we noted that CMP has the responsibility to determine whether all discount rates and tariffs (which are generally referred to as non-core rates) continue to be necessary to maximize revenues. *Order,* Docket No. 97-580 at 37 (Mar. 19, 1999). In our Order on Reconsideration, we explicitly stated that the continued availability of a core rate would be consistent with the no losers principle, while CMP would maintain flexibility over non-core rates. *Order on Reconsideration,* Docket No. 97-580 at 12 (June 22, 1999). Because special rates and tariffs represent discounts off the regular rates, and are temporary by their nature, the no losers principle was never meant to apply to them. The no losers principle was intended to ensure that customers who did not otherwise have a discount rate would not have the burden of rate increases concurrent with retail access as a result of rate re-design.

To determine whether Rate O is core or non-core, we must examine the availability criteria and purpose of the Rate. As a general rule, core rates are generally available to utility customers based on the size of the customer's load and the voltage upon which service is taken. The purpose of core rates is to charge customers within a class based on the costs of serving that class. The purpose of non-core rates is to maximize revenue by providing discount rates to customers with alternatives (e.g., self-generation). The availability of such rates is thus limited to customers who have demonstrated alternatives.

Rate O has some characteristics of both a core and a non-core rate. Several years ago, the Rate was generally available as an interruptible standby rate. However, in recent years, it was restricted to only a few customers. Additionally, the Rate was listed among CMP's non-core rates in the pricing flexibility portion of its current plan. The rate, however, does not appear to be designed to enhance revenues and was initially conceived as a cost-based interruptible rate.

On balance, we conclude that Rate O is essentially a grandfathered core rate and, as such, CMP should include a T&D version of the Rate in its Phase II-B filing.[13] Consistent with the no losers principle, the Rate should be restricted to customers that are currently eligible to take the service and should be modified to the least extent possible.

4. Rate GSS

We agree with FPL Energy Maine and find that customers that are eligible for Rate GSS should also have the option to take standby service under generally applicable tariffs. This decision will promote fair competition among generators and is consistent with the no losers principle.

As a general matter, competing entities, such as generators in a restructured environment, should not have different costs based on artificial distinctions. Thus, FPL Energy Maine should not have to pay more for standby service simply because it owns a generation facility that was previously jointly owned by CMP. Additionally, Wyman 4 always had the right to take service under the generally available all-requirements rate or Rate SB. Thus, our decision promotes the policy of avoiding rate design losers.

5. Conclusion

To conclude, we note that our decisions regarding standby rates in this Order are solely a result of our attempt to implement the spirit of the no losers principle as announced in the Phase I Order.[14] This principle was adopted so that no electricity customer, either larger customers with self-generation capabilities or smaller customers with no such capabilities, will be harmed by rate structure changes concurrent with retail access. As a consequence, customers with self-generation will be

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[13] We note that retaining the Rate will not significantly impact the general body of ratepayers, but eliminating it could substantially impact customers currently taking the rate. Thus, retaining the Rate is more consistent with the no losers principle.

[14] The IECG has argued in different contexts that the Commission cannot lawfully implement the no losers principle with respect to standby rates. We disagree with the IECG's statutory interpretation in this regard. We note that our decision on standby rates in this Order is premised on our authority to avoid rate design losers in adopting March 1, 2000 standby rates.

able to take advantage of several options for standby rates. This will be the case even though, as a general principle, optional core rates are not favored in that they lead to revenue erosion.

We have previously stated that the underlying cost structures of the new T&D-only utilities will be examined in the future to ensure that rates reasonably reflect costs. When rates are restructured, the no losers test will no longer apply. Consequently, it may well be the case that the structure of standby rates will change significantly and that self-generating customers will no longer be able to pick and choose among several standby rate options. For this reason, standby customers should not rely on the continuation of either the structure of the current standby rates or the existence of options into the future.

VI. PHASE II-B DESIGN OF RATES

In this section, we note several important matters in the design of the T&D-only rates that must be considered in Phase II-B.

A. Top-Down Methodology

In our *Order Provisionally Designating Standard Offer Providers and Rejecting Certain Bids*, Docket No. 99-111 (Oct. 25, 1999), we rejected all bids for CMP's service territory because acceptance would not be in the public interest. We stated that the results of the process suggest problems with the emerging electric markets in the region.

Due to this development, it may not be appropriate to use the standard offer prices to unbundle generation costs from current costs. Thus, in Phase II-B, we will consider alternative approaches to implementing the top-down methodology.

B. Non-Core Rates

In establishing the ultimate T&D revenue requirements and rates, we must account for the contribution from non-core rates. To a large degree, this contribution will depend on the cost of generation service from the market. At this point, it appears that standard offer prices may not be a reasonable proxy for such costs.

We expect CMP will continue to negotiate with non-core customers over the next several months. Our hope is that the results of those negotiations will be known in time to be reflected in the March 2000 rates. To the extent actual results are not known in time, we will use the best available estimates.

At the time of its Phase II-B filing, CMP should provide a status report on its negotiations and expected timeframe for completing the negotiations.

C. Rate A

In our Phase I Order, we indicated that Rate A should be flattened if it can be done without creating unacceptable bill impacts. In its Phase II filing, CMP presented bill impact analyses, based on differing assumptions about standard offer and entitlements sale prices. Because a final determination on this matter must be based on actual standard offer and entitlement sale prices, we will consider the degree to which Rate A may be flattened in Phase II-B.

VII. CONCLUSION

As this decision indicates, most of the issues regarding the setting of CMP's T&D rates for the rate period beginning at the start of retail competition have now been addressed. There are still many areas where the best information will not be available until nearly the time that retail competition will begin. We therefore have not attempted as part of this analysis to provide a revenue requirement number or a projection of rate levels at the start of retail access because such projections could easily be misinterpreted and would not be meaningful given the amount of "filling in" that still needs to be done. The interests of both the public and the Company will be served by waiting until the results of both the QF auction and the standard offer bid process are known, before committing to a particular course in areas such as amortization periods, where the Commission retains a considerable amount of flexibility. In several weeks we will conclude Phase II-B, the final phase of this proceeding. The Phase II-B proceeding will reflect the decisions reached here and in our Phase I Order and will also incorporate the results of the standard offer bid and QF bid processes. We will, at the conclusion of that proceeding, establish T&D rates for CMP to commence on March 1, 2000, the start of retail access to generation services in Maine.

Dated at Augusta, Maine, this 19th day of January, 2000.

BY ORDER OF THE COMMISSION

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Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Diamond

This Document has been designated for publication

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 30 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Civil Procedure, Rule 73, et seq.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

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